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# The Challenges Facing the Industry in Offshore Facility Decommissioning on the California Coast

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## Abstract

This paper addresses the challenges of decommissioning oil and gas facilities offshore California, where there are a number of large, deep-water platforms, and decommissioning infrastructure and services are severely lacking. The regulatory process for decommissioning platforms is also very complex and expensive and the prospects for reefing platform jackets are uncertain at best. These circumstances have created a situation that the domestic oil and gas industry has not really faced before, i.e., that the cost risk may not be determinate. This will pose a major challenge to decommissioning project management. The paper addresses the major issues and attempts to put boundaries on the cost risk.

## Introduction

Decommissioning oil and gas facilities offshore California will be a very challenging and expensive process when compared to the U.S, Gulf of Mexico (GOM), where there exists a robust infrastructure to support decommissioning operations, and where approximately 150-200 offshore structures are removed annually. This paper provides an overview of the potential offshore decommissioning market in California and discusses some of the challenges and risks that companies face in planning and conducting decommissioning projects. The challenges and risks are many and include:

1. Limited experience removing large deep-water platforms
2. Lack of infrastructure and high vessel mobilization costs
3. Limited onshore materials processing and disposal options
4. A complex regulatory framework
5. Stringent marine mammal protection requirements
6. Restrictive air emission requirements
7. Uncertain site clearance requirements for shell mounds
8. An untested and problematic rigs-to-reef process

This paper discusses recent cost estimates for decommissioning oil and gas facilities offshore California, and projects how the cost estimates could increase taking into consideration the challenges, risks and uncertainties noted above.

## Federal OCS Oil and Gas Facilities

There are 23 oil and gas platforms operated by six companies (operators) on the Federal Outer Continental Shelf (OCS), offshore California (Table 1). The OCS platforms are jointly regulated by the U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM). They are located in southern California offshore Los Angeles, Orange, Ventura, and Santa Barbara Counties (Figure 1). The OCS platforms are located between 3-10 miles offshore in water depths ranging from 95 to 1,198 feet and, with the exception of Platform Gina (1,380 short tons), range in total weight from 4,000 to more than 86,000 short tons. Approximately 750 wells have been drilled from the platforms.

**TABLE 1 - FEDERAL OCS PLATFORMS LOCATED OFFSHORE CALIFORNIA**

| Platform | Year Installed | and Age (years) | Operating Status Jan. 2018 | Water Depth (feet) | Total Weight (s. tons) | Wells | OCS Operator[1] |
|---|---|---|---|---|---|---|---|
| **San Pedro Bay – Los Angeles and Orange County** | | | | | | | |
| Eureka | 1984 | 33 | Producing | 700 | 33,377 | 50 | BOC |
| Elly[2] | 1980 | 37 | Active | 255 | 9,400 | 0 | BOC |
| Ellen | 1980 | 37 | Producing | 265 | 11,665 | 63 | BOC |
| Edith | 1983 | 34 | Producing | 161 | 8,556 | 18 | DCOR |
| **Eastern Santa Barbara Channel – Ventura and Santa Barbara County** | | | | | | | |
| Hogan | 1967 | 50 | Producing | 154 | 5,098 | 39 | POO |
| Houchin | 1968 | 49 | Producing | 163 | 5,615 | 35 | POO |
| A | 1968 | 49 | Producing | 188 | 4,896 | 52 | DCOR |
| B | 1968 | 49 | Producing | 190 | 4,959 | 57 | DCOR |
| C | 1977 | 33 | Producing | 192 | 5,718 | 38 | DCOR |
| Henry | 1979 | 38 | Producing | 173 | 4,006 | 23 | DCOR |
| Hillhouse | 1969 | 48 | Producing | 190 | 5,834 | 47 | DCOR |
| Gina | 1980 | 37 | Producing | 95 | 1,380 | 12 | DCOR |
| Gilda | 1981 | 36 | Producing | 205 | 11,293 | 63 | DCOR |
| Habitat[3] | 1981 | 36 | Shut-in | 290 | 9,611 | 20 | DCOR |
| Gail | 1987 | 30 | Shut-in | 739 | 37,057 | 27 | BWEG |
| Grace | 1979 | 38 | Shut-in | 318 | 13,074 | 28 | BWEG |
| **Western Santa Barbara Channel – Santa Barbara County** | | | | | | | |
| Hondo[3] | 1976 | 41 | Shut-in | 842 | 29,478 | 28 | EMC |
| Harmony[3] | 1989 | 28 | Shut-in | 1,198 | 86,513 | 34 | EMC |
| Heritage[3] | 1989 | 28 | Shut-in | 1,075 | 69,192 | 48 | EMC |
| **Santa Maria Basin – Santa Barbara County** | | | | | | | |
| Harvest[3] | 1985 | 32 | Shut-in | 675 | 35,150 | 19 | FMCOG |
| Hermosa[3] | 1985 | 32 | Shut-in | 603 | 30,868 | 13 | FMCOG |
| Hidalgo[3] | 1986 | 31 | Shut-in | 430 | 23,384 | 14 | FMCOG |
| Irene | 1985 | 32 | Producing | 242 | 8,762 | 26 | FMCOG |

Source: BSEE, 2016 and BOEM, 2017

[1] Operators: Beta Operating Company, LLC (BOC); Pacific Operators Offshore, LLC (POO); Dos Cuadras Offshore Resources, LLC (DCOR); Beacon West Energy Group, LLC (BWEG); ExxonMobil Corp. (EMC): Freeport McMoran Oil, Gas, LLC (FMCOG)

[2] Platform Elly is a production handling and processing platform for Platforms Ellen and Eureka.

[3] Platforms have been shut-in since the May 2015 Plains All American Pipeline L.P. (PAAP) Line 901 onshore pipeline rupture.

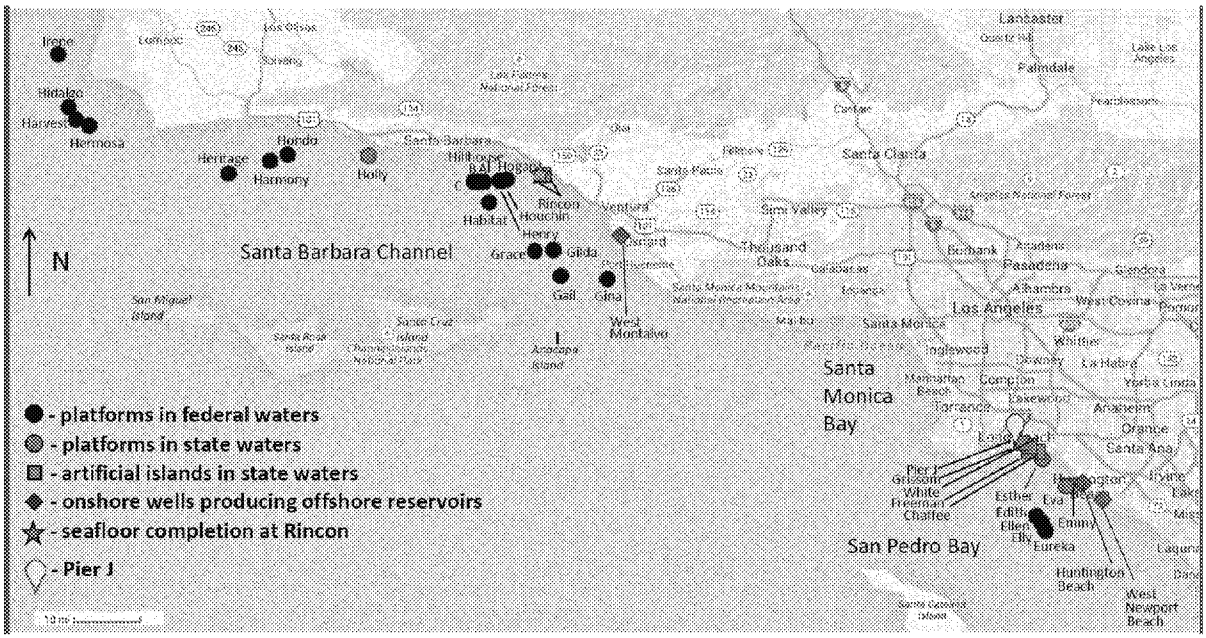


**Figure 1 - California Offshore Oil and Gas Facilities**
(Source, Lawrence Berkeley National Laboratory, 2015)

The first phase of OCS development began in the 1960's when Platforms Hogan, Houchin, A, B, and Hillhouse were installed. This was followed in the 1970's with the installation of Hondo, C, Henry, and Grace. The third and final phase of development occurred in the 1980's when 14 platforms were installed, the last two of which were Heritage and Harmony in 1989. Figure 2 shows that 13 of the 23 OCS platforms exceed 35 years in age, which exceeds the economic lifespan of most platforms. Trends in OCS oil and gas production also demonstrate that many of the OCS platforms may be nearing or already have reached the end of their economic life.

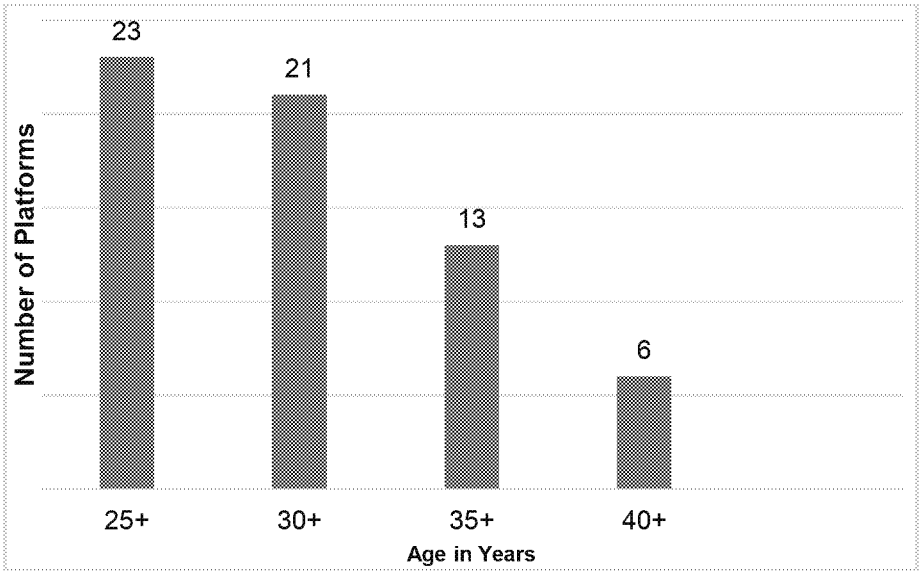


**Figure 2 - The Age Distribution of California OCS Platforms**
(Source: BSEE, 2016 and BOEM, 2017)

As shown in Figure 3, OCS production levels have been decreasing since reaching an annual peak at 72.4 million barrels of oil (MBO) and 75 billion cubic feet of natural gas (BCFG) in 1995 and 2000, respectively. By 2014 annual production levels dropped to 18.4 MBO and 28.2 BCFG as reservoir pressures declined before dropping further in 2015 to 11.4 MBO and 14.7 BCFG, primarily in response to an onshore pipeline break which shut-down production at six OCS platforms. Annual production continued to drop to 6.1 MBO and 4.5 BCFG in 2016 and an estimated 4.5 MBO and 3.1 BCFG in 2017 due to the combined effect of high costs of production, low oil and gas prices, and platform shut-ins. Although production is expected to eventually resume at some of the shut-in platforms, the downward trend in production is expected to continue unless there is a significant and pro-longed increase in the price of oil.

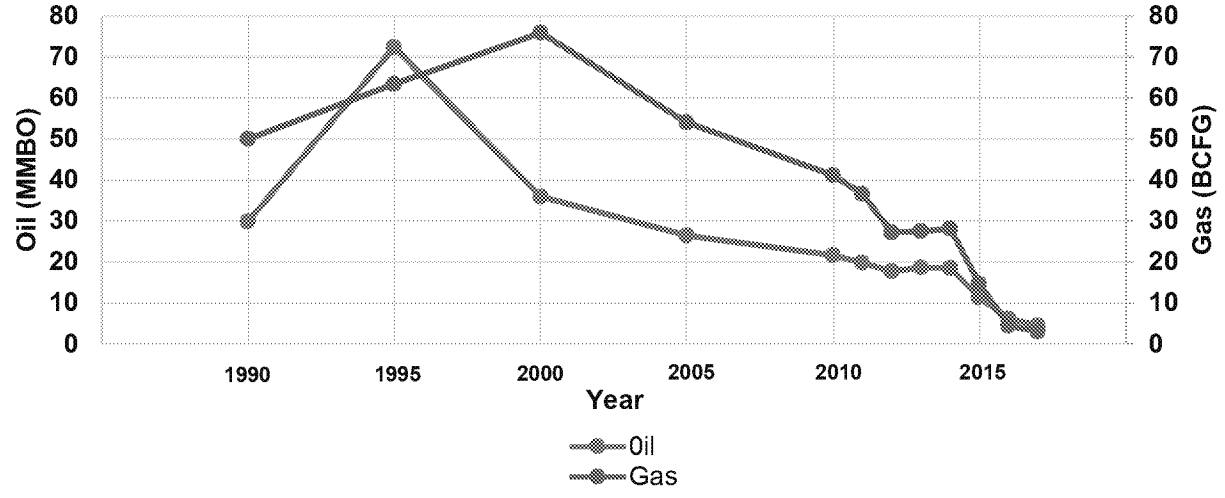


**Figure 3 - California Offshore Oil and Gas Production History 1990 to 2017 (Source: BSEE 2017)**

Table 1 also shows the current (January 2018) operating status of the 23 OCS platforms. Platforms Harvest, Hermosa, Hidalgo in the Santa Maria Basin, and Hondo, Harmony, and Heritage in Western Santa Barbara Channel, have been shut-in since May 2015 due to the onshore rupture of the Plains All America Pipeline (PAAP) (Line 901) that, along with PAAP Line 903, transported oil produced by the platforms to processing facilities and destination points in San Luis Obispo and Kern County. On August 15, 2015, PAAP submitted applications to install 123 miles of new pipeline to replace the 901 and 903 Lines, along with supporting access roads, valves and pump station (Santa Barbara County, 2017). PAAP projects it will take about two years to permit, and 18 months to install the new pipelines (Pacific Coast Business Times, 2017).

Based on PAAP's projection, oil transportation by pipeline would resume between 2020 and 2022. Production is expected to eventually resume at Platform Hondo, Harmony and Heritage to recover the large oil and gas reserves remaining in ExxonMobil Corporation's (ExxonMobil) Santa Ynez Unit. The situation is much less clear for Platforms Harvest, Hermosa and Hidalgo, where high operating costs combined with low oil and gas prices have resulted in a large drop in production since they were installed in 1985 and 1986. Production at the platforms shut in

due to the PAAP Line 903 pipeline break is not likely to resume until the new onshore transportation pipelines are installed unless operators can obtain approval from Santa Barbara County and other regulatory agencies to truck oil to processing facilities while the new pipeline is being constructed.

Other OCS platforms currently shut-in are Platforms Gail, Grace and Platform Habitat. Platforms Gail and Grace were operated by Venoco, LLC (Venoco), which filed for bankruptcy protection and has relinquished the OCS leases for Gail and Grace. The platforms are now operated by the Beacon West Energy Group, LLC, and under the control of Chevron USA, Inc. (Chevron), which is developing plans to decommission the platforms. Platform Habitat is primarily a gas production platform that has ceased production due to a combination of high operating costs, low oil and gas prices, and limited market for the quality of gas it produced.

## State Offshore Oil and Gas Facilities

State jurisdiction offshore California extends from the coastline to a distance of three statute miles offshore. There are nine oil and gas production facilities in state waters, four platforms and five artificial islands (Table 2, Figure 1). The four platforms and Rincon Island are on State Tidelands leases that were granted by California State Lands Commission (CSLC). The remaining four artificial islands, Chaffee, White, Freeman and Grissom, are in San Pedro Bay on offshore lands owned by the City of Long Beach. The state platforms range in age from 32-54 years, and the artificial islands from 51-59 years. Platform Holly is located two miles offshore the City of Goleta in Santa Barbara County. It is situated in 211 feet of water, weighs

**TABLE 2 - OIL AND GAS PRODUCTION FACILITIES LOCATED IN CALIFORNIA STATE WATERS**

| Platforms | Year Installed and Age (years) | | Water Depth (feet) | Location | Current Status | Well Slots | Operator |
|---|---|---|---|---|---|---|---|
| Emmy | 1963 | 54 | 47 | Huntington Beach, Orange County | Producing | 64 | SoCal Holdings, LLC |
| Eva | 1964 | 53 | 57 | Huntington Beach, Orange County | Producing | 44 | DCOR, LLC |
| Esther | 1985 | 32 | 22 | Seal Beach, Los Angeles County | Producing | 64 | DCOR, LLC |
| Holly | 1966 | 51 | 211 | Goleta, Santa Barbara County | Shut-in | 30 | CSLC; prior operator was Venoco, LLC |
| **Artificial Islands** | | | | | | | |
| Chaffee | 1966 | 51 | 40 | Long Beach, Los Angeles County | Producing | 387 | THUMS Long Beach Company |
| Freeman | 1966 | 51 | 40 | Long Beach, Los Angeles County | Producing | 357 | THUMS Long Beach Company |
| White | 1966 | 51 | 40 | Long Beach, Los Angeles County | Producing | 338 | THUMS Long Beach Company |
| Grissom | 1966 | 51 | 40 | Long Beach, Los Angeles County | Producing | 394 | THUMS Long Beach Company |
| Rincon[1] | 1958 | 59 | 44 | Ventura County | Shut-in | 69 | CSLC; prior operator was Rincon Island Limited Partner. |

(Source: CSLC, 2017)

[1] There is also one idle subsea well that is connected with Rincon Island.

approximately 8,700 tons, and is the largest state water platform. Platforms Eva, Esther and Emmy are located between two-three miles offshore Orange County in water depths ranging from 22-57 feet. The five artificial islands are in water depths ranging from 40-44 feet. All the platforms and artificial islands in state waters are producing except Platform Holly and Rincon Island, which are shut-in due to bankruptcy filings by Venoco and Rincon Island Limited Partnership, respectively.

**Decommissioning History and Outlook**

To date, only seven small platforms and one artificial island have been decommissioned and removed offshore California. All of the facilities decommissioned were in state waters. The most recent platform decommissioning project occurred more than 20 years ago in 1996 when Chevron removed Platforms Hope, Heidi, Hilda, and Hazel (Basavalinganadoddi, 2004). The platforms were located offshore Santa Barbara County in water depths ranging from 100-140 feet, and had a combined steel weight of approximately 10,000 tons. The platforms were removed over a 70-day period during the summer of 1996 using the reverse installation process by a locally stationed derrick barge (DB *Wotan*), which had a maximum rotating-lift capacity of 350-400 tons. The topsides were removed in 100-400 ton lift packages. The jackets were cut-up by divers using arc-oxygen torches and removed in sections. About 30-40 lifts were made to remove each jacket.

The topsides and jackets, with the exception of the several large caissons at Platform Helen which were permitted to remain in-place, were transported by tugboats and cargo barges from the Santa Barbara Channel 100 miles south to Terminal Island in Long Beach, where they were offloaded, cut-up, and recycled. Due to the lack crane lifting capacity at the port, the DB *Wotan* was required to accompany the tugboats and cargo barges to port to offload the heavier topside modules and jacket sections. Several roundtrips were required to offload the materials.

The most recent offshore decommissioning project occurred in 2001, when ExxonMobil removed Belmont Island, an oil and gas production facility in Long Beach Harbor (Mount, 2005). Belmont Island consisted of a large concrete and sand filled caisson through which wells were drilled. The island was totally removed and the armor rock protecting the caisson was relocated to an offshore artificial reef managed by the California Department of Fish and Wildlife. The only decommissioning project on the OCS to date was ExxonMobil's Offshore Storage and Treatment (OS&T) project. The OS&T was a converted oil tanker moored offshore Santa Barbara County. The OS&T and its moorings were removed from the seafloor in 1994.

Several recent events in California provide indications that offshore decommissioning activity is likely to commence and pick-up in the next several years. The most significant event that has changed the outlook for decommissioning in California occurred when Venoco filed for relief under Chapter 11 of the U.S Bankruptcy Code on April 17, 2017. They concurrently quitclaimed interests in three California State Tidelands leases that included Platform Holly and two Ellwood Beach oil piers containing two idle wells (CSLC, 2017a). The quitclaim effectively ended commercial oil and gas production on the leases and returned operational control of the assets to CSLC. CSLC does not have the option to re-lease the lands because the California Coastal Sanctuary Act prohibits the CSLC from issuing new oil and gas leases in state waters.

The CSLC subsequently retained the services of the Beacon West Energy Group, LLC to continue safe operations at Platform Holly and the associated onshore Ellwood Processing

Facility located in Goleta, California, and plug and abandon 30 wells on Platform Holly and two wells on the piers. In August of 2017, CSLC signed a "Letter of Intent" with ExxonMobil, predecessor lessee to Venoco, detailing the decommissioning obligations and responsibilities of each party (CSLC, 2017b). The CSLC estimates it will take about two years to plug and abandon the wells, and several more years to obtain permits and remove the platform.

The CSLC decision to decommission Platform Holly is a potential game changer because it may prompt other oil and gas operators to consider decommissioning, particularly if significant cost savings can be achieved by collaborating on a multiple platform decommissioning project. Collaboration would allow companies to share the cost of mobilizing heavy lift vessels/derrick barges (HLV/DB) from the GOM, North Sea, or Asia Pacific. The HLV/DB contracted to remove Platform Holly, for example, could be used to remove platforms of similar size that are located in Eastern Santa Barbara Channel (see Table 1). Candidate platforms for decommissioning would be those nearing the end of their economic life as demonstrated by low production levels, high operating costs, and depleted reserves. The larger platforms, such as Harvest, Hermosa and Hidalgo, may also be candidates for decommissioning, but would require the mobilization of a much larger HLV/DB having the lift capacity required to safely make heavy lifts in the challenging oceanographic conditions encountered in the Santa Maria Basin.

Operators could also achieve significant cost savings by jointly covering the cost of mobilizing a dynamically positioned dive support vessel (DPDSV) to California, as well as other decommissioning services such as rig-less well plugging and abandonment and abrasive and mechanical cutting services.

**Limited Experience Removing Large Deep-water Platforms**

The 23 OCS platforms offshore California are steel-jacketed structures that are fixed to the seabed and secured by pilings typically driven through the platform legs to a depth of several hundred feet below the surface of the seafloor. Eight of the 23 platforms have estimated total removal weights exceeding 23,000 tons and are in +400 feet water depths (Table 3). In 2016, an industry journal reported only 15 offshore platforms weighing more than 14,000 tons had been removed worldwide (Upstream Intelligence, 2016). In the GOM, only 11 structures (platforms and compliant towers) were reported to have been removed in water depths exceeding 400 feet as of January 1, 2013 (Wang, 2014). Most, if not all of these projects, involved removing the upper portion of the platform jacket to a depth of 85 feet below the ocean surface and converting the remaining structure to an artificial reef in place. In other projects, the jackets were detached from the seabed and towed to an approved reef site. There have also been several deep-water platform jackets removed in the North Sea, but the footings of some of the jackets were permitted to remain in-place.

Several oil and gas companies have begun engineering studies to evaluate removal options for decommissioning large deep-water platforms offshore California. Topsides removal options under study include:

1. Reverse installation
2. Small to medium piece removal
3. Large, single-piece removal using a unique one-of-a-kind vessel such as the *Pioneering Spirit*

Jacket removal options under study include:

1. Cutting the jackets into large sections weighing up to 2,000 tons using divers/ROV's (depending on the capability of the selected HVL/DB)
2. Cutting the jackets into many small, lighter pieces

Detailed material disposal options are also being investigated to evaluate the capabilities of ports to offload and process/recycle the platform steel and other materials. The options under consideration include:

1. The Ports of Los Angeles and Long Beach
2. A recycling facility located in Mexico
3. Facilities located in the GOM

Future deep-water decommissioning projects in California will be some of the largest and most technically challenging marine demolition projects ever undertaken. The projects will require years of advanced planning, extensive surveys and data collection, and engineering analyses. Detailed environmental studies and analyses will also be required of various removal and materials disposition options, including reefing of the platform jackets. In some cases, new or innovative technology may need to be developed and utilized to remove the footings/pilings of

**TABLE 3 - ESTIMATED REMOVAL WEIGHTS FOR OCS OIL AND GAS PLATFORMS LOCATED OFFSHORE CALIFORNIA (SHORT TONS)**

| Platform | Water Depth (feet) | Deck Weight | Jacket Weight | Pile Weight | Conductor Count and Weight | | Total Removal Weight |
|---|---|---|---|---|---|---|---|
| **San Pedro Bay – Los Angeles and Orange County** | | | | | | | |
| Eureka | 700 | 8,000 | 19,000 | 2,000 | 60 | 4,377 | 33,377 |
| Elly | 255 | 4,700 | 3,300 | 1,400 | 0 | 0 | 9,400 |
| Ellen | 265 | 5,300 | 3,200 | 1,100 | 64 | 2,065 | 11,665 |
| Edith | 161 | 4,134 | 3,454 | 450 | 29 | 518 | 8,556 |
| **Eastern Santa Barbara Channel – Ventura and Santa Barbara County** | | | | | | | |
| Hogan | 154 | 2,259 | 1,263 | 150 | 39 | 1,426 | 5,098 |
| Houchin | 163 | 2,591 | 1,486 | 150 | 35 | 1,388 | 5,615 |
| A | 188 | 1,357 | 1,500 | 600 | 55 | 1,439 | 4,896 |
| B | 190 | 1,357 | 1,500 | 600 | 56 | 1,502 | 4,959 |
| C | 192 | 1,357 | 1,500 | 600 | 37 | 2,261 | 5,718 |
| Henry | 173 | 1,371 | 1,311 | 150 | 24 | 1,174 | 4,006 |
| Hillhouse | 190 | 1,200 | 1,500 | 400 | 50 | 2,734 | 5,834 |
| Gina | 95 | 447 | 434 | 125 | 12 | 374 | 1,380 |
| Gilda | 205 | 3,792 | 3,220 | 1,030 | 62 | 3,251 | 11,293 |
| Habitat | 290 | 3,514 | 2,550 | 1,500 | 21 | 2,047 | 9,611 |
| Gail | 739 | 7,693 | 18,300 | 4,000 | 29 | 7,064 | 37,057 |
| Grace | 318 | 3,800 | 3,090 | 1,500 | 38 | 4,684 | 13,074 |
| **Western Santa Barbara Channel – Santa Barbara County** | | | | | | | |
| Hondo | 842 | 8,450 | 12,200 | 2,900 | 28 | 5,928 | 29,478 |
| Harmony | 1,198 | 9,839 | 42,900 | 12,350 | 54 | 21,424 | 86,513 |
| Heritage | 1,075 | 9,826 | 32,420 | 13,950 | 49 | 12,996 | 69,192 |
| **Santa Maria Basin – Santa Barbara County** | | | | | | | |
| Harvest | 675 | 9,024 | 16,633 | 3,383 | 25 | 6,110 | 35,150 |
| Hermosa | 603 | 7,830 | 17,000 | 2,500 | 29 | 3,538 | 30,868 |
| Hidalgo | 430 | 8,100 | 10,950 | 2,000 | 14 | 2,334 | 23,384 |
| Irene | 242 | 2,500 | 3,100 | 1,500 | 28 | 1,662 | 8,762 |

(Source: BSEE, 2016)

deep-water jackets, which were not designed with removal in mind.

**Lack of Infrastructure and High Vessel Mobilization Costs**

The market for offshore decommissioning equipment and services is practically non-existent in California as compared to the GOM, where approximately 100-150 offshore oil and gas structures are currently being removed annually. As previously noted, only seven oil and gas platforms have been removed offshore California, the most recent in 1996 when Chevron removed four small platforms from state waters. Due to the lack of decommissioning and oil and gas development activity on the west coast, HLV/DB companies and other contractors who provide decommissioning services in the U.S. are concentrated in the GOM, Asia Pacific or Europe. This includes offshore construction companies such as Manson Construction Company (Manson), which following the Chevron 4-H project, transferred the DB *Wotan* from California to the GOM to take advantage of marketing opportunities there. Other decommissioning services such as DPDSV's, abrasive and mechanical cutting services, and rig-less well P&A services are also primarily concentrated in the GOM, Asia Pacific and the North Sea.

At present, the largest HLV/DB in southern California is Manson's DB *Valhalla*, currently stationed in Los Angeles Harbor. The *Valhalla* typically works in local harbors and near-shore waters. The maximum rotating-lift capacity of the barge is 350 tons which may be sufficient to remove some of the smaller, shallow water platforms offshore California using piece small techniques. The DB *Valhalla*, however, does not have berthing capacity to accommodate offshore workers, and would be much more susceptible to shut-down due to adverse weather and sea conditions than a larger HLV/DB. Much larger HLV/DB's will be required to safely and efficiently remove the mid-water and deep-water platforms.

Decommissioning cost studies conducted by TSB Offshore, Inc. (TSB) for BSEE determined that HLV/DB's having a rotating-lift capability ranging from 500 tons to 4,000 tons or more would be suitable for removing California platforms (BSEE, 2016). The HLV/DB's will likely be required to be mobilized from the GOM, North Sea, or Asia Pacific at significant expense. The time required to mobilize a HLV/DB to California can range from a minimum of 65 days up to as much as 180 days depending on the size of the HLV/DB, the distance it has to travel, and whether it can pass through the Panama Canal. The recent Panamax expansion can accommodate vessels with a length up to 1,253 feet, a beam up to 407 feet, and a draft up to 89 feet. There are also a number of height restrictions to be considered for the derrick cranes on some of the larger HVL/DBs due to a number of bridges over the canal. The lowest of these is 200 feet at high tide for the Bridge of the Americas. An HLV/DB based in the GOM or North Sea exceeding these dimensions would need to make the long transit to southern California around South America via the Straits of Magellan.

As shown in Table 4, the estimated cost to mobilize a HLV/DB could range from nearly $12 million to $73 million depending on the type of HLV/DB selected and roundtrip travel time. In comparison, HLV/DB mobilization times and costs in the GOM typically range between 2-6 days, and $200,000 to $600,000. The mobilization cost problem becomes much more severe for large, deep-water platforms because multiple HLV/DB mobilizations may be required to fully remove the structures. For deep-water projects such as Harvest, Hermosa, and Hidalgo in the Santa Maria Basin, industry engineering studies have estimated it would take approximately 100-200 days to remove a single platform jacket using large HLV/DB's having a lift capacity of 3,000-4,000 tons. Due to the challenging oceanographic conditions and short working season (90-120 days) in the Santa Maria Basin, two separate HLV/DB mobilizations may be required to remove

a single jacket, and possibly up to six mobilizations for all three platform jackets, not counting the HLV/DB time to remove the topsides of the platforms.

**TABLE 4 - ESTIMATED TIME AND COST FOR MOBILIZING HLV/DB'S TO SOUTHERN CALIFORNIA**

| Vessel Type | Max. Lift Capability (short tons) | | Region of Departure | Time Days | Vessel Day Rate | Total Cost[1] |
|---|---|---|---|---|---|---|
| Small DB | 500 - 600 | | GOM | 80 | $165,000 | $11,880,000 |
| Large DB | 2,000 - 3,000 | | GOM | 80 | $250,000 | $18,000,000 |
| HLV. | 2,000 - 3,000 | | S.E. Asia | 100 | $250,000 | $22,500,000 |
| HLV. | 3,000 - 4,000 | | North Sea | 180 | $350,000 | $56,700,000 |
| HLV | 4,000 - 5,000 | | North Sea | 180 | $450,000 | $72,900,000 |
| HLV | 7,000 - 7,500 | | S.E. Asia | 100 | $550,000 | $49,500,000 |

[1] Cost is calculated as follows: #days x vessel day rate x 90% to account for reduced crew and operating costs during transit; vessel day rates are estimates based on TSB vessel cost surveys.

Multiple mobilizations could be avoided by using a world-class HLV such as the recently commissioned *Pioneering Spirit*, a 1,253 feet-long and 407 feet-wide double hulled HLV designed to lift up to 53,000-ton topsides and 27,500-ton jackets in a single lift. This may not be a viable option, however, unless a suitable port can be found having the capability to offload and dismantle the topsides and jacket.

Mobilization costs would be much lower if a large HLV/DB having sufficient lifting capacities to remove the platforms became stationed in southern California for an extended period of time or permanently. The California decommissioning market does not appear robust enough for that to happen, however, given the limited number of platforms (27) and their variable cessation of production timeframes. Mobilization and platform removal costs could be significantly reduced if operators can obtain approval to reef platform jackets. However, the prospects for reefing are uncertain, at best, as will be discussed later in this paper.

Other vessels and equipment that will be needed to support decommissioning operations in California are DPDSV's, abrasive and mechanical cutting services, ROVs, and rig-less well plugging and abandonment services. A DPDSV would likely be used to assist in the decommissioning of platforms in +300 feet water depths to support saturation diving operations, abrasive and mechanical cutting equipment, and house work crews. The DPDSV would likely be mobilized from the GOM or Asia Pacific. Assuming a roundtrip time of 40 days at a DPDSV day rate of $90,000, mobilization costs would total $3.6 million.

### Limited Onshore Materials Processing and Disposal Options

There are very limited onshore disposal options for decommissioned oil and gas platforms in California. The only port-based facilities that process scrap in the region are the Terminal Island and Berth 118 facilities operated by SA Recycling in Long Beach and Los Angeles, California (Weiner, 2010). The facilities collect and process heavy industrial scrap such as autos and rail cars by shredding the metals into sizes approximately three-feet square or less. Berth 118 is situated on a 16-acre site in the Port of Long Beach, California. The facility is equipped with a ship-loading crane having a lifting capacity of approximately 150 tons, a large 1,000-ton Guillotine Shear and two mobile "T" shears. The maximum throughput capacity of the facility is approximately 3,600 short tons per day. The Terminal Island facility is situated on a 26-acre site at Pier S, on Terminal Island in the Port of Los Angeles. The facility is equipped with a mega shredder and a 2,000-ton hydraulic shear that can cut steel plates up to three inches thick by 30 feet long. The maximum throughput capacity of the facility is approximately 5,200 short tons per

day.

The SA Recycling facilities are the only locations where bulk vessels are loaded with scrap in southern California. Both facilities have hard-standing dock areas that can accommodate vessels having a length of 600-750 feet and a loaded capacity of 50,000 long tons. Due to the limited market for scrap steel on the west coast, the majority of the scrap is sold and shipped in bulk carriers to Asian markets such as China, India, Vietnam, Thailand and South Korea.

Decommissioning projects that involve removing several platforms at a time, particularly the larger, deep-water structures, will generate large volumes of steel and other materials (cement, plastics, wood etc.) far exceeding the combined capacity of the Terminal Island and Berth 118 facilities, absent a major expansion and upgrade of the facilities, which may not be possible given the growing demand for space within the port and the limited space available. It is also not clear whether the port and local communities would support an expansion of recycling facilities to accommodate oil and gas platform demolition operations due to environmental concerns and past experience during the Chevron 4-H project. During the Chevron 4-H project, marine growth clinging to the platform jackets emitted strong odors which resulted in numerous complaints by port workers and the public. This led to pronouncements by port and local government officials that similar operations may not be approved in the future unless marine growth is removed from the platform jacket sections before they are offloaded at port. This would require removing the marine growth from platform jackets in-situ, using divers and ROV's, or removing the marine growth from the jackets after they have been placed onboard barges using water-jetting equipment. A special permit would be required from federal and/or state water quality agencies to dispose of marine growth overboard, but not in-situ.

As shown in Table 3, the removal of three to four platforms weighing 5,000 tons each in the Eastern Santa Barbara Channel would generate 15,000-20,000 tons of steel and other materials. The removal of three to four large deep-water platforms, in comparison, could generate 90,000 to more than 180,000 tons of material. Projects of this scale will far surpass the capacities of existing facilities on the west coast and necessitate consideration of other disposal options, including expanding existing facilities, building new facilities on the west coast, or transporting the materials by sea to Mexico, the GOM or Asia Pacific.

**Complex Regulatory Framework**

There are a number of Federal, State and local agencies that regulate decommissioning operations in federal and state waters, or are responsible for protecting natural resources that could be impacted by decommissioning operations. Federal agencies include: BOEM, BSEE, National Marine Fisheries Service (NMFS), U.S. Army Corps of Engineers (ACOE), U.S. Fish and Wildlife Service (USFWS), U.S. Environmental Protection Agency (EPA), U.S. Coast Guard (USCG), and the U.S. Department of Transportation, Office of Pipeline Safety (DOT/OPS). State and local agencies having regulatory and resource management responsibilities include the California Coastal Commission (CCC), CSLC, California Department of Fish and Wildlife (CDFW), California Division of Oil, Gas, and Geothermal Resources (DOGGR), Ventura County Air Pollution Control District, Santa Barbara Air Pollution Control District, South Coast Air Quality Management District, and county planning and resource management departments. A listing of the agencies and their regulatory responsibilities is provided in Tables 5 and 6.

Depending on the scope of the project, operators may need to obtain 10-20 separate major

permits from federal, state and local regulatory agencies for a project involving the decommissioning of platforms, pipelines, power cables, and associated onshore facilities. In some cases, it may take as long as one year or more to obtain air emission permits, or permits to convert a platform jacket to an artificial reef. Due to the numerous permits required and the complexity of the process, operators of oil and gas facilities offshore California have typically contracted with local consulting firms having the technical, environmental and regulatory expertise required to navigate through the regulatory maze.

For decommissioning projects in state waters, operators are required to fund the preparation of a California Environmental Quality Act (CEQA) environmental document, which can be an Environmental Impact Report (EIR) or Negative Declaration, depending on the scope of the project and potential environmental impacts. The CSLC is typically the lead state agency dealing with the CEQA; in cases where projects occur on offshore lands granted to the county the county may be the CEQA lead agency. For projects on the OCS, BSEE will be the lead federal agency and conduct environmental review of the project in accordance with the National Environmental Policy Act (NEPA). The option also exists for BSEE and CSLC to prepare a joint NEPA/CEQA environmental document for an OCS platform decommissioning project that also involves associated state water and onshore components such as pipelines, power cables, and processing facilities. Operators can expect to expend $500,000 to $1 million to support preparation of an EIR, EIS or joint EIR/EIS. For projects generating opposition and public controversy, such as those where reefing is proposed, costs could increase by a factor of two or more.

**TABLE 5 - FEDERAL PERMITTING REQUIREMENTS FOR DECOMMISSIONING PROJECTS**

| Agency | Regulatory Responsibility | Authority |
|---|---|---|
| BOEM | Administers OCS leases and enforces bonding requirements and compliance with lease terms and conditions. | Outer Continental Shelf Lands Act, 30 CFR § 550 and 30 CFR § 556 |
| BSEE | Permits OCS decommissioning operations and enforces safety and environmental regulations. Lead NEPA agency on federal OCS. | Outer Continental Shelf Lands Act, 30 CFR § 250<br>National Environmental Policy Act |
| ACOE | Permits discharges of dredged or fill material in U.S. waters, and permits for construction of any structure in or over the navigable waters of the U.S.; Lead NEPA agency in state waters. | Clean Water Act, Section 404<br>Rivers and Harbors Act, Section 10 |
| USFWS | Protection of threatened and endangered species (e.g. sea otters and certain bird species). | Endangered Species Act<br>Migratory Bird Treaty Act |
| NMFS | Protection of threatened and endangered species, marine mammals, and essential fish habitat. | Endangered Species Act<br>Marine Mammal Protection Act<br>Magnuson-Stevens Fisheries Conservation and Mgmt. Act |
| EPA | Issues National Pollution Discharge Elimination System (NPDES) permits for discharges of pollutants from point sources in federal waters. | Clean Water Act |
| USCG | Administers U.S. Aids to Navigation System; directs responses to unauthorized discharges including oil spills. | Ports and Waterways Safety Act<br>Clean Water Act<br>Oil Pollution Act of 1990 |
| DOT/OPS | Regulates DOT pipelines | Natural Gas Pipeline Safety Act<br>Hazard. Liquid Pipeline Safety Act<br>Hazard. Materials Transport. Act |

In addition to NEPA/CEQA costs, operators planning to undertake decommissioning projects offshore California will incur additional expenses in obtaining the necessary federal, state, and local permits required to conduct decommissioning operations. Many state and local regulatory

agencies, for example, impose fees on project applicants to cover permit application processing fees and staff time. Applicants must also cover the costs of complying with expensive environmental mitigation measures attached to permits issued by the agencies.

**TABLE 6 - STATE AND LOCAL PERMITTING REQUIREMENTS FOR DECOMMISSIONING PROJECTS**

| Agency | Regulatory Responsibility | Authority |
|---|---|---|
| CSLC | Issues permits for decommissioning activities in state waters; typically serves as lead CEQA agency | California Public Resources Code, Section 6500<br>CEQA |
| DOGGR | In coordination with CSLC, regulates plugging and abandonment of wells in state waters and onshore lands in California | California Public Resources Code, Title 14 |
| CCC | Issues Coastal Development Permit for decommissioning activities in state waters and onshore lands within the coastal zone under CCC jurisdiction; also conducts consistency review of decommissioning activities on the federal OCS | California Coastal Act<br>Coastal Zone Management Act |
| CDFW | Issues permits for artificial reefs, and the use of explosives in state waters; conducts review of projects to ensure protection of state endangered species | California Public Resources Code, Section 1601<br>California Endangered Species Act<br>Fish and Wildlife Coordination Act |
| RWQCB | Regulates discharges that may affect surface and ground water quality in state waters | Clean Water Act<br>Porter-Cologne State Water Quality Act |
| SHPO | Conducts review of proposed activities to ensure protection of historic and pre-historic resources | National Historic Preservation Act |
| **Local Agencies (Ventura, Santa Barbara, Los Angeles County)** | | |
| County Planning and Resource Mgmt. Depts. | Issues Coastal Development Permit for onshore decommissioning activities on lands under local coastal program jurisdiction | County General Plan and County Coastal CZM Plan where applicable |
| County APCD | Issues Permit to Operate/Authority to Construct and portable engine permits | Clean Air Act |

Examples include marine mammal protection measures, air emission mitigation measures, mitigation monitoring programs, and pre- and post-decommissioning biological surveys. Depending on the location of the project, commercial fishing preclusion agreements may be necessary to minimize or eliminate the potential for conflict. A recent decommissioning cost report prepared by TSB for BSEE estimated the direct permitting costs to total $4.5 million per project (BSEE, 2016). The cost related to the permitting impact on a project schedule will be discussed below.

### Stringent Marine Mammal Protection Requirements

The Southern California Bight includes at least 34 species of marine mammals that have been identified by biological surveys. The primary marine mammals that frequent the areas around offshore oil and gas platforms include cetaceans (whales and dolphins), pinnipeds (seals and sea lions), and the southern sea otter (BOEM/BSEE, 2016).

One of the major challenges operators face in planning and conducting decommissioning operations in California are restrictions that could be placed on heavy marine construction and the use of explosives to protect marine mammals by regulatory agencies such as CDFW, CSLC, CCC, NMFS, and the USFWS. During the Chevron 4-H project, for example, heavy marine construction, and the use of explosives, were not permitted during the six-month gray whale migration period from November 1 through May 31 (CCC, 1995).

Other measures taken by Chevron during the 4-H project to address agency concerns and avoid impacts to marine mammals included:

1. Placing observers on vessels to monitor the area prior to, during, and after the detonation of explosive charges.
2. Conducting 30-minute aerial surveys by qualified observers one hour prior to detonations.
3. Delaying detonations until no marine mammals were observed within 1,000 yards of the platforms.
4. Requiring detonations to be conducted during daylight hours only.
5. Requiring all detonations to be staggered, below the mudline, and inside the platform legs and casings.
6. Placing a killer whale sonic warning system in the water near the platforms and activating it prior to detonations.
7. Conducting pre- and post-detonation surveys by divers to observe and recover fish injured or killed.

Following the Chevron 4-H Project, the Eastern North Pacific Stock of gray whales was removed from the U.S. List of Endangered Wildlife based on evidence the species had recovered to their estimated original population size. Operators may be able to make a case the Chevron 4-H heavy marine construction prohibition, adopted more than 20 years ago, is no longer necessary given the delisting of the gray whale, and the advancements made in decommissioning technology and procedures. Obtaining approval to use explosives is likely to be much more difficult due to agency concerns with potential impacts to marine mammals, fish, and other sensitive species. Recent advances in abrasive and mechanical cutting will eliminate much of this risk and additional expense. Early consultations with regulatory agencies will be required to determine what decommissioning procedures will be permitted.

**Restrictive Air Emission Requirements**

Air quality in California is regulated by the California Air Resources Board (CARB) and county air pollution control districts (APCD). The CARB has established stringent state ambient air quality standards for criteria pollutants to protect public health and welfare. Criteria pollutants include oxides of nitrogen (NOx), oxides of sulfur (SOx), ozone, carbon monoxide, and particulate matter less than 10 microns in diameter (PM 10), and less than 2.5 microns (PM 2.5) in diameter (BOEM/BSEE, 2016).

The county APCD's are responsible for enforcing federal and state standards. California offshore oil and gas platforms operate under permits issued by: (1) South Coast Air Quality Management District, (2) Ventura County APCD, and (3) Santa Barbara County APCD (SBC APCD). The permits cover routine emissions from platform cranes, compressors, emergency generators and fugitive hydrocarbons from valves, flanges and other equipment. The permits, however, do not include the large emissions generated by decommissioning operations which include NOx and reactive organic compounds (ROC), precursor pollutants for ozone, and particulate matter. The three districts are also classified as non-attainment areas for ozone and particulate matter. The permits issued by the APCD's therefore place strict limitations on emissions.

A review of the APCD permitting process for the1996 Chevron 4-H project provides a perspective on potential pitfalls and challenges operators may encounter in obtaining permits for decommissioning projects. As noted earlier, the project involved removing four platforms in state

waters offshore Santa Barbara County. During the project, more than 120,000 gallons of fuel were used which led to the emission of 21.6 tons of NOx, 1.3 tons of ROC, 14.2 tons of carbon monoxide (CO), 0.5 tons of sulfur (SOx), and 1.3 tons of PM (Sheehan, 1997).

The Chevron 4-H permitting process began when Chevron submitted an Execution Plan to CSLC in November 1993 providing a description of decommissioning procedures, vessels, and equipment to be used during the project. The Execution Plan was used by CSLC to prepare a CEQA Mitigated Negative Declaration (MND) describing the environmental impacts of the project and mitigation measures. The MND, approved by CSLC in August 1994, estimated 57.6 tons of NOx would be emitted by the project, and required Chevron to implement the following required mitigation measures (CSLC, 1994):

1. Equipment shall be maintained as per manufacturer's specifications.
2. Catalytic converters shall be installed on all gasoline-powered equipment, if applicable.
3. The fuel injection timing shall be retarded on all gasoline powered equipment by two degrees from manufacturer's recommendations.
4. Gasoline powered equipment shall be substituted for diesel powered equipment, if feasible.
5. Direct injection diesel engines (i.e. Caterpillar D399 or equivalent) shall be used if available.
6. Turbocharged diesel engines with inter cooling shall be used if available.
7. Reformulated diesel fuel and high-pressure injectors shall be used in all diesel-powered removal and abandonment equipment.

In April 1995 a problem developed when Chevron applied for Authority to Construct and Permit to Operate (ATC/PTO) permits from SBC APCD, and provided revised estimates for air emissions based on engine-specific information not available at the time CSLC approved the MND. The new NOx estimate was 79.3 tons, an increase of 21.7 tons above the amount (57.6 tons) estimated in the CSLC MND (Sheehan, 1997). This exceeded SBC APCD's threshold levels for Best Available Control Technology, air quality modeling, and emission offsets. This delayed approval of ATC/PTO permits to allow time for Chevron to acquire the required mitigating offsets for the additional emissions, and for SBC APCD to conduct a supplemental CEQA review to support issuance of the permits. The offsets were eventually obtained by Chevron when it reached agreements with local commercial/recreational fishermen to install advanced low-emission electronically-controlled diesel engines on five fishing boats. The final ATC/PTO permits were issued by SBC APCD in February 1996. Chevron, however, could not begin demolition operations until May 1, 1996 due to the prohibition of heavy marine construction operations during the gray whale migration season. The end result was a one-year postponement in the project from the summer of 1995 to the summer of 1996.

Delays in obtaining APCD permits, such as those encountered by Chevron, have the potential to impact construction schedules and can be very costly if contracts for vessels, equipment and other decommissioning services have to be cancelled or altered. In California, the risks are higher due to the complexity of the APCD permitting process and prohibition of heavy marine construction during the gray whale migration period. The schedule and cost impact of this are discussed below.

**Uncertain Site Clearance Requirements for Shell Mounds**

One of the issues that remains unresolved in California are site clearance requirements for shell mounds. Shell mounds consist of drill muds and cuttings discharged from the platforms that have deposited on the seafloor along with shell material from natural litter-fall and cleaning marine growth from the platform legs. The shell mounds are known to contain chemical contaminants including metals, hydrocarbons, and polychlorinated biphenyls (PCBs).

The shell mounds that formed under each of the Chevron 4-H platforms (Hope, Heidi, Hilda, Hazel) rise to a height of 25-28 feet above the ocean floor, and cover areas measuring 220-240 feet in diameter; the four mounds are estimated to collectively contain 45,000 cubic yards of material (Basavalinganadoddi, 2004). One of the permit conditions placed on the project by CSLC required test trawling to demonstrate the area around the four platforms was clear of obstructions. When test trawling of the area was performed after the platforms were removed, nets caught on the shell mounds and trawling was unsuccessful. Several commercial fishing associations and environmental groups objected to leaving the shell mounds in-place and insisted the ocean floor be restored to its natural condition. Some government agencies expressed concern that removing the shell mounds may do more environmental damage than leaving them in-place due to the toxic materials present in the shell mounds.

The Chevron 4-H shell mound issue has remained unresolved for more than 20 years despite several attempts by Chevron and CSLC to reach a settlement acceptable to all parties. In 2013, Chevron submitted a proposed project to CSLC that involved:

1. Quitclaiming Chevron's interest in the leases where the platforms were sited.
2. Leaving in-place the shell mounds.
3. Enhancing the Carpinteria Salt Marsh by removing non-native vegetation and sediments to improve tidal circulation.
4. Providing funds for additional future marsh and/or coastal habitat improvements, or other conservation purposes.

In the spring of 2013, the CSLC began preparing an EIR for the project, pursuant to CEQA. The CSLC "Notice of Intent" to prepare the EIR stated the document will evaluate Chevron's proposed project and other alternatives including full removal, capping the mounds, and building artificial reefs over the mounds (Santa Barbara County, 2017a).

Work on the EIR has been suspended. CSLC decisions on how it will proceed are pending. CSLC's final decision on Chevron's 4-H shell mounds will likely set a precedent for addressing shell mound issues at other platform sites, including those on the OCS, where large shell mounds have built-up at many platforms, particularly those in the Eastern Santa Barbara Channel (MMS, 2003). Given the limits of dredging vessels on the west coast, which operate in water depths of less than 100 feet, off-site mitigation appears to be the only reasonable option in cases where shell mounds are demonstrated to pose an obstacle to commercial trawlers, or potential environmental risk due to contaminants. The mitigation could include restoration of coastal areas, funding for compensation projects, and compensation to commercial fishermen for loss of trawling grounds. The costs to operators are difficult to estimate, but could range from several hundred thousand to as much as $1 million per location, depending on the size and complexity of the mounds.

**An Untested and Problematic Rigs-to-Reef Process**

Obtaining approval to reef an oil and gas platform will be much more difficult in California than it is in the GOM, where 515 decommissioned platforms were converted to artificial reefs as of January 1, 2017 (BSEE, 2017a). To date, only seven small, shallow water platforms have been decommissioned offshore California and all were completely removed. Most of the platforms were briefly considered for reefing, but all were fully removed primarily due to the lack of any legal and regulatory authority for the state to consider reefing ownership and responsibility for managing the reef.

There have been no oil and gas platform decommissioning projects conducted offshore California since rigs-to-reef legislation, the *California Marine Resources Legacy Act* (AB 2503), was enacted in 2010. The reefing process in California is therefore untested and highly uncertain given the number of regulatory agencies involved in the process and the stringent conditions that must be met under AB 2503. This situation, coupled with the potential for legal challenges from environmental organizations and other parties, creates significant uncertainties that greatly complicate the logistical planning process, and increases the level of financial risk faced by operators if decommissioning operations cannot be conducted as planned due to permit denials or litigation.

AB 2503 established state policy that allowed, on a case-to-case basis, the partial removal of a platform jacket and the conversion of the jacket to an artificial reef managed by the California Department of Fish and Wildlife (CDFW). The reefing program is voluntary and platforms in both state and federal waters are eligible to be reefed.

AB 2503 also requires that certain conditions must be met before reefing is considered. These include, among others, that the creation of the reef results in a "net environmental benefit to the marine environment", and that a portion of the cost savings to the platform owner from partial, as opposed to full removal, will be deposited in the California Endowment for Marine Preservation. To provide incentives for early decommissioning, the act mandated the percentage of cost savings to be shared with the State increase over time as follows: 55% by January 1, 2017; 65% between January 1, 2017 and January 1, 2023; and 80% after January 1, 2023.

Under AB 2503, six separate State entities have responsibility for administering various aspects of the reefing program:

1. California Department of Fish and Wildlife (CDFW): has the primary authority for implementing the program and is responsible for reviewing and approving reefing applications, preparing, updating and approving reef management plans, holding public hearings to solicit public input on reefing proposals, and managing and operating the reef.
2. California Natural Resources Agency (CNRA): serves as the lead agency for conducting an environmental review of the reefing proposal in accordance with CEQA.
3. California Ocean Protection Council (OPC): is responsible for determining whether the partial removal of a platform would result in a net environmental benefit and developing criteria to make that determination.
4. California State Lands Commission (CSLC): is responsible for determining the amount of cost savings that would be saved by reefing as compared to full removal.

5. State Coastal Conservancy: is responsible for developing an advisory spending plan for the cost savings deposited in an endowment.
6. California Coastal Commission (CCC): has authority for approving coastal development permits for reefs located in state waters, and conducts consistency reviews of decommissioning and reefing activities in federal waters that could affect coastal zone resources.

AB 2503 requires companies submitting reefing applications to cover the costs incurred by agencies to process the application, including the costs required to support preparation of environmental documents required to comply with CEQA. The act also requires the first reefing applicant to cover CDFW's costs to set-up the reefing program.

AB 2503 also sets-forth several important agreements that must be enforced between the applicant and CDFW before conditional approval of a reef is granted by the CDFW. These include:

1. An agreement between the owner/applicant and CDFW to support the overall management of the reef
2. An agreement between the owner/applicant and CDFW to indemnify and protect the State from liability
3. An agreement between the owner/applicant of the platform and CDFW for the CDFW to take title to the reef

During the past several years there have been several attempts to amend AB 2503 to streamline and improve the permitting process which is viewed by the oil and gas industry to be overly complex and inefficient. The proposed amendments would improve the act in several important areas by:

1. Streamlining the permitting process by transferring CEQA responsibilities from CNRA to CSLC
2. Updating and adjusting the donation timing and cost sharing formula
3. Addressing industry liability concerns
4. Including consideration of air emissions and impacts on global warming in the net environmental benefit analysis
5. Providing for a more equitable sharing of costs for setting up the CDFW reefing program among reefing applicants

Although AB 2503 has been in force since 2010, companies have not yet taken advantage of the law. Industry representatives say this is, in part, because they are concerned about liability issues, the high cost the initial applicant would incur in supporting the initial development of the reefing program, and the requirement that 65-85% of the cost savings from reefing be shared with the state. According to one estimate, potential savings to the industry from converting all 23 OCS platform jackets and piles offshore California to reefs, rather than removing them, could be as much as $1 billion (Hahn, 2003). Under AB 2503, $650-$850 million of the $1 billion in savings would go to the California Endowment for Marine Preservation if all the platforms were reefed. The economic incentives for operators to reef a platform in California are therefore quite limited compared to the GOM where operators typically donate 50% of the cost savings to Texas, Louisiana, Mississippi and Alabama reefing programs.

The costs to set-up a reefing program in California will also be substantial. According to the California Senate Appropriations Committee, it will cost $4-$6 million to set-up the reefing program and $1-$2 million annually to manage the program, broken down as follows (California Senate Rules Committee, 2017):

1. $1.5 million annually for CDFW staffing.
2. $440,000 in year 1, and ongoing cost of $540,000 per year to the OPC for staffing and contracting costs.
3. $3.0-$3.75 million to prepare the first platform specific decommissioning Environmental Impact Report (EIR), and up to $2.25 million to the programmatic EIR for all remaining structures.
4. Several hundred thousand dollars annually to cover California Coastal Commission permitting expenses.

Although some of these costs would be reimbursable, the write-off may not provide industry with sufficient incentives to consider reefing given other factors such as the potential for litigation by the Sierra Club, the Environmental Defense Center, the Pacific Coast Federation of Fishermen's Association, and other entities who have opposed reefing of platforms offshore California in the past. Many of these parties remain strongly opposed to reefing platform jackets despite the fact studies have demonstrated oil and gas platforms offshore California are among the most productive marine fish habitats in the world (Claisse, 2014).

**Risk Factors for Estimating Decommissioning Costs**

In 2016 TSB developed estimated costs for decommissioning the 23 federal OCS platforms located offshore California for BSEE (BSEE, 2016). A summary of these costs is available on the BSEE public website.

These costs can be broken down for each platform into the following categories:

1. Platform Removal
2. Well P&A
3. Conductor Removal
4. Permitting and Regulatory Compliance
5. Mobilization and Demobilization of the HVL/DB
6. Materials Disposal
7. Other Costs
8. Total Costs

The "Other Costs" category includes such items as pipelines, cables, site clearance, contingences, etc. The items specifically listed represent approximately 70% of the total costs of decommissioning. This study had as its primary objective providing BSEE and BOEM a base line reference for determining bonding requirements for the operators and lessees. The objective was to determine the likely costs that could be achieved by a well-managed project under good working conditions, i.e., GOM work conditions using West Coast costs. **These costs were deterministic costs in that no assessment of risk is applied to the various cost items.** Operator overhead and the wide array of risk factors discussed above were not considered in the cost. The remainder of this paper will attempt to put bounds on some of these risk items. **The "Risk Cost Factors" selected below to develop the sample Decommissioning Costs**

**shown below are based on the collective experience and judgement of the authors, in light of the fact that there is no actual history of platform decommissioning in California in federal waters that can be used as a guideline.**

Table 7 shows assigned potential change factors for the project cost items addressed in the BSEE study for the purpose of project cost modelling. Factors less than one indicate the prospect of improvement from the presented deterministic costs, while numbers greater than one show the assessed risk of cost increase. These factors are used to generate a uniform probability distribution function (PDF) for cost modelling in a Monte Carlo project simulation.

**TABLE 7 - COST RISK FACTORS**

| | Risk Factors | | | |
|---|---|---|---|---|
| **Project Cost Items** | **Potential Max. Cost Decrease** | **Base Case BSEE 2016 Cost Report** | **P50 With Uniform Distribution** | **Potential Max. Cost Escalation** |
| Platform Removal (<400 ft.) | 0.8 | 1.0 | 2.9 | 5.0 |
| Platform Removal (>400 ft.) | 1.0 | 1.0 | 5.5 | 10.0 |
| Well P&A | 0.9 | 1.0 | 2.0 | 3.0 |
| Conductor Removal | 0.8 | 1.0 | 1.9 | 3.0 |
| Permitting & Reg. Compliance | 1.0 | 1.0 | 3.0 | 5.0 |
| Mob & Demob of DB (<400 ft.) | 0.8 | 1.0 | 1.4 | 2.0 |
| Mob & Demob of DB (>400 ft.) | 1.0 | 1.0 | 5.5 | 10.0 |
| Material Disposal (<400 ft.) | 1.0 | 1.0 | 5.5 | 10.0 |
| Material Disposal (>400 ft.) | 1.0 | 1.0 | 25.5 | 50.0 |
| Other Costs | 0.8 | 1.0 | 1.9 | 3.0 |

Consideration/discussion of the risk factors is as follows:

*Platform Removal* – This series of tasks includes a wide variety of offshore work functions, e.g., pile severing, deck removal, jacket removal, etc. There is some room for modifications to the BSEE study, particularly in the shallower water facilities. However, given the complexity of the regulatory environment, there is much more room for delay and cancelled contracts, leading to greatly increased, if not out-of-control cost. This will be the highest profile portion of the work. One can argue that there is no upper bound on these costs. Moreover, the risk will be greater for the deep-water platforms since jacket weight increases more or less exponentially with water depth. Therefore, different risk factors are used for the platforms in water depths greater than 400 feet.

*Well Plugging and Abandonment (P&A)* – Well P&A is not likely to be impacted by permitting delays. There is generally always some room for reducing costs by improving the efficiency of the process. However, the age of the wells and potential to encounter unexpected problems produces many more opportunities for overruns.

*Conductor Removal* – Conductors can be removed before the arrival of the DB/HLV's as a part of the P&A program or they can be removed by the DB/HLV's with the platform topsides and jacket. In the latter case, risks increase due to the potential for unexpected permitting delays. This is a part of the project that is very vulnerable to cost increases. No major platform decommissioning project has ever been attempted on the California OCS. The regulatory environment is extremely complex and completely untested. Given the need for the operators to award contracts years in advance in many cases, the risks are magnified.

*Mob & Demob of Derrick Barges* – There is some potential cost reduction upside here if a company decides to base DB/HLV's and other equipment on the West Coast. However, there is likely more downside potential than upside due to the small number (27) of platforms offshore California and their different cessation of production timelines. Since larger equipment will be needed for the deeper water platforms, different factors are used for greater than 400 feet depths. Depending on the offshore project location and related work season associated with each location, standby periods between summer working seasons, and the related cost, is also a major factor.

*Materials Disposal* – Regulatory issues notwithstanding, this is likely the greatest risk item in California OCSR decommissioning. Today there is no practical place to put the removed material. Only a small amount can go into the Ports of Los Angeles and Long Beach. Transporting unprocessed material to Asia is not feasible. There simply aren't enough barges of the right size to move the material in the condition that it would normally be removed, and there are no places on the California coast to process it into more manageable sizes. The likely processing sites will be in Mexico, but this presents huge political and technical issues. It's hard to put an upper bound on the cost of this issue. Since more material volume is generated with the deeper water platforms, different factors are used for greater than 400 feet depths.

**Estimating the Cost Impact**

To assess the impact of risk on California offshore decommissioning, the risk factors of Table 7 have been applied to the costs shown in the BSEE study using probabilistic cost estimating methods. The risk factors were assumed to have uniform distribution since we have no information that would indicate otherwise. This assumed probability distribution was used in a Monte Carlo simulation model to produce a probabilistic estimate of the cost resulting from the assessed risk with each of the decommissioning cost elements identified above. The resulting mean (average) cost for the cost elements and the totals for platform depth ranges are shown in Table 8.

Figure 4 shows the Cumulative Distribution Function (CDF) for the total OCS platform decommissioning cost with risk. Table 9 shows the estimated range of total decommissioning cost (P10 to P90) for all of the California Federal waters platforms by depth range. The CDF's for all platforms are very similar to that of the total cost shown in Figure 4.

**Conclusions & Recommendations**

It can be argued that the risk factors in Table 7 are not rigorously determined and that the distribution of risk is not likely to be uniform as assumed. The former, of course, could be true and it is likely not possible to determine the actual distribution of risk. These assumptions are simply based on the judgement of knowledgeable professionals who are very familiar with all aspects of the situation in California related to offshore facility decommissioning. Others with similar knowledge are invited to express their own opinions. What appears to be very clear is that oil and gas facility decommissioning offshore California will be very risky from a cost standpoint. The work presented shows that these costs could easily be off by more than a factor of 4 relative to the 2016 BSEE study which has been referenced. The four principle cost risk drivers are:

| TABLE 8 - THE ESTIMATED COST OF DECOMMISSIONING THE POCSR FACILITIES WITH RISK (Mean in US$ Millions) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Platform Depth Range** | **Platform Removal w/ Risk** | **Well P&A w/ Risk** | **Conductor Removal w/ Risk** | **Permitting & Reg. Compliance w/ Risk** | **Mob & Demob w/ Risk** | **Materials Disposal w/ Risk** | **Other Costs w/ Risk** | **Mean Total Cost w/ Risk** | **Total Cost (BSEE 2016)** |
| **<200 feet** | 116 | 102 | 51 | 30 | 62 | 99 | 151 | 611 | 272 |
| **200 - 400 feet** | 118 | 74 | 41 | 18 | 40 | 141 | 154 | 586 | 241 |
| **400 - 800 feet** | 1,131 | 52 | 61 | 21 | 95 | 1,667 | 269 | 3,296 | 495 |
| **>800 feet** | 944 | 57 | 79 | 13 | 103 | 1,836 | 231 | 3,263 | 459 |
| **Total** | 2,309 | 285 | 232 | 82 | 300 | 3,743 | 805 | 7,756 | 1,467 |

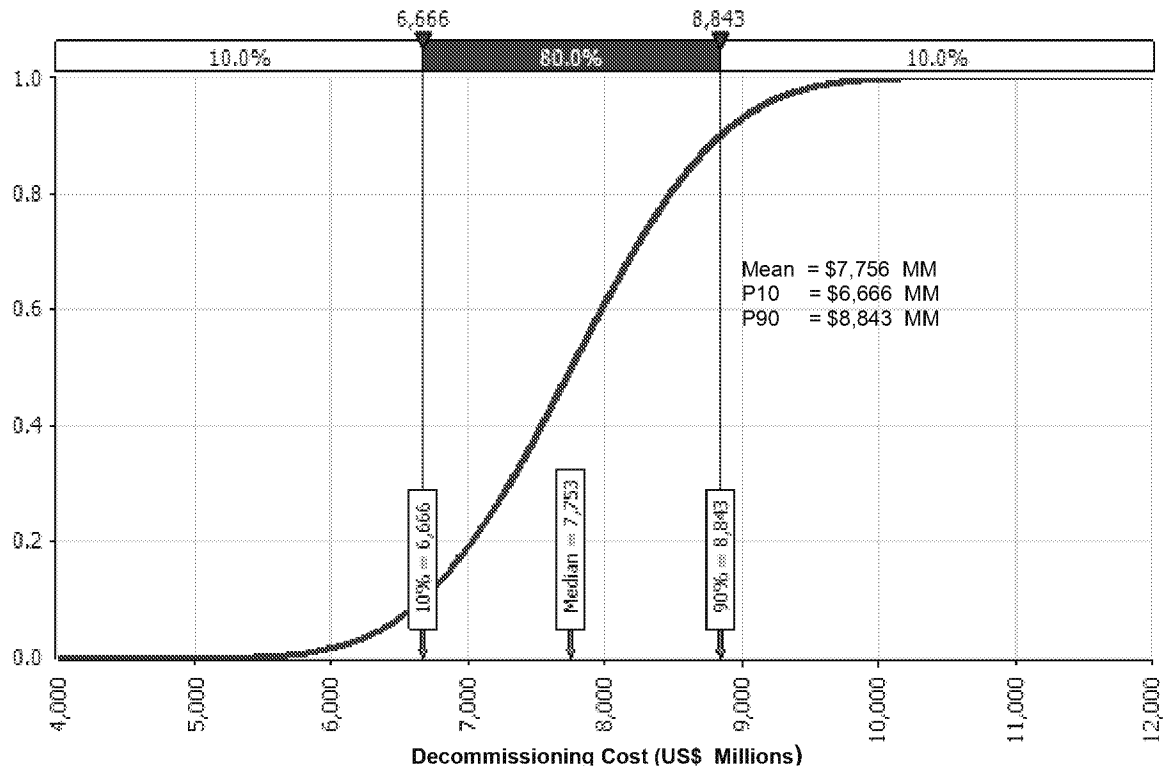


**Figure 4 - CDF of California OCS Platform Total Decommissioning Cost with Risk**

| TABLE 9 - THE ESTIMATED RANGE OF TOTAL COST OF DECOMMISSIONING WITH RISK (US$ Millions) | | | |
|---|---|---|---|
| **Platform Depth Range** | **P10 Total Cost** | **Mean Total Cost** | **P90 Total Cost** |
| <200 feet | 568 | 611 | 654 |
| 200 - 400 feet | 529 | 586 | 641 |
| 400 - 800 feet | 2,668 | 3,296 | 3,921 |
| >800 feet | 2,365 | 3,263 | 4,165 |
| Total | | 7,756 | |

1. **The complex regulatory environment** which makes it very difficult to obtain permit approvals and establish firm schedules for DB/HLV's and decommissioning services. This is driven by the impact of multiple agencies having overlapping authority over various aspects of the decommissioning process, and regulatory uncertainties that exist due to ssthe lack of decommissioning history offshore California. The permitting process is largely untested, particularly for projects where reefing of platform jackets is proposed. This will complicate the decommissioning planning process and increase the level of risks faced by operators and lessees who need to contract for DB/HLV's and other decommissioning services years in advance.
2. **The age and size of many of the facilities.** The smaller facilities are generally more than 30 years old. A number of the larger facilities are among the largest ever built, in addition to being old. The combination of age and size would make these projects challenging under any conditions.
3. **The remoteness of the California facilities relative to the resources that are required for their removal.** (DPDSV's, HLV/DB's, large cargo barges, etc. This will require careful advanced planning and a well-thought-out contracting strategy. The seasonal nature of the work in some areas makes this even more complicated.
4. **The almost complete lack of local facilities for the disposal of the removed material**. The only relevant example available, Chevron's 4-H's project, proved how difficult it would be, even for small facilities. There are simply no facilities available on the entire U.S. West Coast for disposal of the larger facilities. The options of transporting the material to the GOM or Asia Pacific would also be extremely challenging due to the types of vessels and barges required and the distances involved. Transporting the platform material to Mexico may be an attractive option if suitable facilities for offloading and processing the materials are available, and firm assurances can be obtained from Mexican officials to accept the materials.

To address regulatory uncertainties and inherent cost risks, we recommend lessees and operators of offshore oil and gas facilities do the following:

1. **Begin planning for decommissioning platforms at least 3-5 years before planned cessation of production (COP).** For large deep-water platforms, the planning process should begin even earlier to ensure the necessary technical and engineering analyses and materials disposal studies are completed in a timely manner.
2. **Consider collaborating with other lessees and operators**, where practicable and feasible, to jointly mobilize HLV/DB's and other equipment to remove multiple platforms during a single campaign.
3. **Establish a local presence by opening and staffing an office** to plan and coordinate decommissioning planning activities with local regulatory agencies and interface with the public, non-government organizations, commercial and recreational fishermen, and other interested parties.
4. **Schedule outreach and coordination meetings with the key Federal, State and local regulatory agencies** early and throughout the decommissioning planning process to solicit input on regulatory requirements and potential mitigation measures that can be adopted to address environmental concerns.

5. **Work closely with the California Interagency Decommissioning Working Group (IDWG),** which is composed of members from Federal, State and local government agencies that regulate decommissioning activities or are responsible for protecting environmental resources that could be impacted by decommissioning operations. The IDWG provides a forum for agencies to collectively discuss decommissioning issues and coordinate the agency permitting process.

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